Vamsi Chadalavada
Senior Vice President
Market and System Solutions

September 21, 2005

Mr. David H. Meyer
Acting Deputy Director
Office of Electricity Delivery and
Energy Reliability
U.S. Department of Energy
Washington, DC 20585

Re: ISO-NE Answers to DOE Questions on Economic Dispatch

Dear Mr. Meyer:

On behalf of ISO-NE, the following is in response to your September 1, 2005, letter containing questions for stakeholders arising out of the Energy Policy Act of 2005, Section 1234 Economic Dispatch Study.

1. What are the procedures now used in your region for economic dispatch? Who is performing the dispatch (a utility, an ISO or RTO, or other) and over how large an area (geographic scope, MW load, MW generation resources, number of retail customers within the dispatch area)?

Answer:

ISO-NE performs the economic dispatch for the New England Control Area (which spans the six-state New England region) with a peak load of 26,922 MW (established on July 27, 2005) and over 31,000 MW of installed generation capacity. ISO-NE oversees a power system with approximately 350 generating units, 8,000 miles of high-voltage transmission lines, and 12 interconnections to neighboring systems – all serving 6.5 million household and business retail customers.

The procedures for economic dispatch are described in the ISO New England Inc. (ISO-NE)'s Manual 11.[1] The following is a high level summary of the procedures.

The Dispatch process includes system control, Ancillary Service monitoring, and transmission system monitoring and control. During the dispatching process, the ISO implements and adjusts the Current Operating Plan, which is developed during the scheduling processes, as needed throughout the Operating Day, maintains reliability and minimizes the cost of supplying the energy, reserves, and other services that are required by the Market Participants and Transmission Customers and the operation of the New England Control Area.

[1] ISO New England Manuals: http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

During the scheduling and dispatch process, the ISO:

1. Clears the Day-Ahead Energy Market using least-cost security-constrained unit commitment and dispatch software,
2. Determines a Current Operating Plan for the Real-Time Energy Market to reliably serve the hourly energy and reserve requirements of the New England Control Area by minimizing the cost to provide sufficient capacity to meet the hourly energy and reserve requirements,
3. Performs hourly scheduling of internal Generators, External Transactions and Dispatchable Load in the Real-Time Energy Market throughout the Operating Day and update the Current Operating Plan as required, and
4. Performs in-hour dispatch of generators, on a continuous basis for the Dispatch of Regulating Generators and normally on a five-minute basis for Energy Dispatch, using the updated Current Operating Plan as a starting point.

In addition to Economic Dispatch and Security Constrained Unit Commitment, ISO-NE runs a competitive wholesale electricity market. More than 260 companies and entities participate in these markets and complete more than $7.25 billion of wholesale electricity transactions annually.[2]

2. Is the Act's definition of economic dispatch (see above) appropriate? Over what geographic scale or area should economic dispatch be practiced? Besides cost and reliability, are there any other factors or considerations that should be considered in economic dispatch, and why?

<u>Answer</u>:

Given a set of unit commitment schedules, the definition in the Act accurately reflects the real-time Security Constrained Economic Dispatch (SCED) performed by ISO-NE. SCED tries to maximize the total social welfare (or minimize the total production cost while maximizing the total consumer benefit) and "reliably serve customers, recognizing any operational limits of generation and transmission facilities."

In general, a larger geographic scale or area (from power system point of view) would produce a bigger benefit due to the savings in market efficiency and economies of scale, but these benefits would have to be weighed against the associated costs. For example, the complexity, technical challenges and risks will also grow exponentially with the scale of the power system. At a certain level, the operator comprehension during times of emergency, modeling complexity, regulatory complexity, the state estimation, and even the supporting computer applications may reach their limits. In other words, with the growth of the economic dispatch footprint, the reliability of the system will not necessarily keep growing – there will be a point after which reliability starts to decline.

Even from the economic point of view, running a Security Constrained Unit Commitment over very large systems does not guarantee an optimum solution, so the savings may not be as great as running economic dispatch over a set of smaller footprint control areas. If trade between control areas is low

[2] These markets have resulted in a dramatic price decline of 11%, after adjustment for fuel costs, in New England from 2001 to 2004. These markets have also led to a reduction in wholesale market costs of approximately $700M (after adjustment for fuel costs)

cost and efficient, the inefficiency from independent economic dispatch should be very low. To the extent that factors such as environmental emissions constraints, fuel limitations, or similar externalities are not included in the costs of units economic efficiency will not be optimal; therefore these factors should be considered in the modeling process.

3. How do economic dispatch procedures differ for different classes of generation, including utility-owned versus non-utility generation? Do actual operational practices differ from the formal procedures required under tariff or federal or state rules, or from the economic dispatch definition above? If there is a difference, please indicate what the difference is, how often this occurs, and its impacts upon non-utility generation and upon retail electricity users. If you have specific analyses or studies that document your position, please provide them.

<u>Answer</u>:

In New England, there is no difference in how utility-owned and non-utility-owned generators are dispatched. ISO-NE's operating procedures follow the formal procedures defined in the market manuals referenced above.

4. What changes in economic dispatch procedures would lead to more non-utility generator dispatch? If you think that changes are needed to current economic dispatch procedures in your area to better enable economic dispatch participation by non-utility generators, please explain the changes you recommend.

<u>Answer</u>:

Currently non-utility generators are efficiently dispatched by ISO-NE based on their economics (i.e., their supply offers). The SCED maximizes the total social welfare, and this objective determines whether to run utility or non-utility-owned generators. SCED does not have information about generation ownership. Therefore, no changes are recommended or needed for the ISO-NE's economic dispatch procedures to accommodate non-utility generators.

5. If economic dispatch causes greater dispatch and use of non-utility generation, what effects might this have – on the grid, on the mix of energy and capacity available to retail customers, to energy prices and costs, to environmental emissions, or other impacts? How would this affect retail customers in particular states or nationwide? If you have specific analyses to support your position, please provide them to us.

<u>Answer</u>:

This question is not applicable to New England. As shown in previous answers, ISO-NE already efficiently dispatches non-utility generation based on their supply offers. The Security Constrained Economic Dispatch treats utility-owned and non-utility-owned generators equally based on their economic offers.

6. Could there be any implications for grid reliability – positive or negative – from greater use of economic dispatch? If so, how should economic dispatch be modified or enhanced to protect reliability?

Answer:

An overly simplified economic dispatch could put the grid reliability in danger. In New England, the addition of security constraints (based on off-line and real-time power flow, voltage and stability analyses as well as contingency analyses) to an economic dispatch, which makes it a Security Constrained Economic Dispatch, enforces reliability of the grid. ISO-NE, for example, has a pre-defined set of approximately 1,000 system contingencies. These contingencies are fully modeled in both real-time dispatch and day-ahead unit commitment. This level of modeling prepares the ISO operators in case of any reliability concerns.

The ability to consider more types of reliability constraints (e.g., voltage, reactive power compensation, stability and ancillary services) explicitly in the Security Constrained Economic Dispatch will further protect the reliability and may potentially improve the overall market efficiency. ISO-NE is in the process of including ancillary services such as operating reserves in its real-time dispatch. Also, ISO-NE is evaluating the use of AC network models that enable explicit modeling of voltage and other constraints.

Please feel free to contact me if I can be of additional assistance providing information on behalf of ISO-NE.

Sincerely,

Vamsi Chadalavada
Senior Vice President
Market and System Solutions
ISO-NE
1 Sullivan Road
Holyoke, MA 01040
Ph: (413) 540-4405
Email: vchadalavada@iso-ne.com

cc: Chairman Donald Downes, CT DPUC
Chairman Kurt Adams, ME PUC
Chairman Paul Alfanso, MA DTE
Chairman Thomas Getz, NH PUC
Chairman Elia Germani, RI PUC
Chairman James Volz, VT PSB
Mr. Bill Nugent, Executive Director NECPUC